UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

August 4, 2010

Brian J. O'Grady, Vice President-Nuclear
and Chief Nuclear Officer
Nebraska Public Power – Cooper
Nuclear Station
72676 648A Avenue
Brownville, NE 68321

Subject: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2010003

Dear Mr. O'Grady:

On June 23, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 1, 2010, with Brian O'Grady, Vice President and Chief Nuclear Officer, and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents two NRC-identified violations, one self-revealing violation and one self-revealing finding of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as a noncited violations, consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the violations or the significance of the noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Cooper Nuclear Station facility. In addition, if you disagree with the crosscutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at Cooper Nuclear Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Vince Gaddy, Chief
Project Branch C
Division of Reactor Projects

Docket: 50-298
License: DRP-46

Enclosure:
NRC Inspection Report 05000298/2010003
w/Attachment: Supplemental Information

cc w/Enclosure:

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ADAMS: □ No x Yes	□ SUNSI Review Complete	Reviewer Initials: VGG
	x Publicly Available	x Non-Sensitive
	□ Non-publicly Available	□ Sensitive

RI:DRP/C	SRI:DRP/C	C:DRS/EB1	S:DRS/TSB	C:DRS/EB2
MLChambers	NHTaylor	TRFarnholtz	MCHay	NFO'Keefe
/RA/	***/RA/***	**/RA/**	***/RA/***	***/RA/***
8/4/10	88/3/10	7/27/10	8/2/10	7/28/10

C:DRS/OB	C:DRS/PSB1	C:DRS/PSB2	C:DRP/C	
MHaire	MPShannon	GEWerner	VGGaddy	
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7/28/10	7/28/10	7/28/10	8/4/10	

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-298
License:	DRP-46
Report:	05000298/2010003
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Ave Brownville, NE 68321
Dates:	March 25 through June 23, 2010
Inspectors:	N. Taylor, Senior Resident Inspector M. Chambers, Resident Inspector R. Hagar, Senior Project Engineer R. Kumana, Project Engineer
Approved By:	Vince Gaddy, Chief, Project Branch C Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000298/2010003; 03/25/2010 – 06/23/2010; Cooper Nuclear Station, Integrated Resident and Regional Report; Equipment Alignments, Maintenance Effectiveness, Event Follow-up, Other Activities

The report covered a 3-month period of inspection by resident inspectors. Four Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of 10 CFR 50.54.j was identified when the licensee failed to ensure that mechanisms which may affect reactivity are manipulated only with the knowledge and consent of a licensed operator at the controls. Specifically, a work planner caused a feedwater heater trip by touching a pressure regulating valve without the knowledge of the control room. This action resulted in a feedwater transient. A subsequent reactivity increase occurred due to the change in feedwater temperature causing the reactor to exceed the licensed thermal power limit of 2419 MWt until reactor operators reduced power. The licensee immediately reduced power using the recirculation pumps. The licensee entered this issue in their corrective action program as CR-CNS-2010-03091.

  The finding was more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event in that a reactor power transient was initiated without the knowledge of the control room. This finding was characterized under the significance determination process as having very low safety significance because while the finding degraded the transient initiator contributor function of the initiating events cornerstone, it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The inspectors determined that this finding has a crosscutting aspect in the area of human performance associated with the work practices component because the work planner proceeded in the face of unexpected circumstances by exceeding the scope of the job when he found the leak was greater than expected [H.4(a)] (Section 4OA3).

- Green. A self-revealing finding was identified for the licensee's failure to implement the preventive maintenance requirements of the vendor manual for the plant traveling water screens. Specifically, Vendor Manual 140, "Traveling Water Screen," Revision 35, contained daily and weekly routine maintenance requirements to open the channel-flushing valve to clear any accumulated debris from the screens. Despite the fact that the licensee incorporated this vendor manual into their preventive maintenance system, this maintenance requirement was overlooked. The failure to perform this maintenance task led to the trip of the A1 and A2 traveling water screens on May 1, 2010, and required an emergent power reduction. The licensee entered this issue in their corrective action program as Condition Report CR-CNS-2010-03195, and implemented daily checks of the traveling water screens and daily flushing of the screen debris troughs.

The finding was more than minor because it affected the equipment performance attribute of the initiating events cornerstone, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding was characterized under the significance determination process as having very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation functions would be unavailable. The inspectors determined that no crosscutting aspect was applicable to this finding because the performance deficiency was not reflective of current performance (Section 4OA5).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation of 10 CFR 50 App B Criterion III, “Design Control,” in which the licensee failed to maintain accurate design drawings of the service water system discharge piping. Specifically, Drawing BR 2120, “Yard Circ. & Service Water Piping Plan & Sections,” Revision 14 incorrectly identified the as-built configuration of the service water system discharge piping, and was used as a design input to numerous essential calculations. The licensee completed an operability evaluation that demonstrated that the service water was operable despite the condition. The licensee entered this issue in their corrective action program as Condition Report CR-CNS-2010-03689.

  The finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was characterized under the significance determination process as having very low safety significance because all of the screening questions in the Manual Chapter 0609, Attachment 4, “Initial Screening and Characterization of Findings” Phase 1 screening table were answered in the negative. The inspectors determined that no cross cutting aspect was applicable to this finding due to the age of the performance deficiency and the lack of recent identification opportunities. (Section 1R04).

- Green. The inspectors identified a noncited violation of 10 CFR 50.65(a)(2), requirements for monitoring the effectiveness of maintenance at nuclear power plants, for failure to demonstrate that the performance of the essential 4160 volt alternating current power system was effectively controlled through appropriate preventive maintenance. As a result, the licensee did not establish goals or monitor the performance of the essential power system Agastat relays per 10 CFR 50.65 (a)(1) to ensure appropriate corrective actions were initiated when a revised evaluation of a Agastat time delay relay failure incorrectly changed the initial functional failure determination. Incorrectly changing this maintenance preventable functional failure resulted in the affected function, EE-PF03A, not reaching the licensee's maintenance rule (a)(1) threshold. The licensee entered this issue in their corrective action program as Condition Report CR-CNS-2008-07910.

This finding is more than minor because it affected the reliability objective of the Equipment Performance attribute under the Mitigating Systems Cornerstone. The inspectors determined that this performance deficiency was an additional, but separate consequence of the degraded performance of the essential 4160 volt alternating current system Agastat relays. Following the guidance of Appendix B to MC0612 and Appendix D to IP 71111.12, the inspectors determined that this finding occurred as a consequence of actual problems with the Agastat relays, and that those actual problems were not attributable to this finding. This finding therefore cannot be processed through the significance determination process, and is considered to be Green by NRC staff review. The finding has a crosscutting aspect in the area of human performance associated with decision-making because the licensee did not use conservative assumptions in the functional failure evaluation of a Agastat relay failure [H.1(b)] (Section 1R12).

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Cooper Nuclear Station began the inspection period at full power on March 24, 2010. On May 1, 2010, the plant reduced power to 70 percent in response to a loss of a circulating water pump due to intake screen fouling. The licensee cleared the screen and returned to 100 percent power later that day. On May 7, 2010, the licensee reduced power to 70 percent for scheduled surveillance testing and returned to 100 percent power On June 4, 2010, the licensee reduced power to 36 percent for scheduled maintenance on the recirculation pump motor generator B. The plant returned to full power on June 10, 2010, where it remained for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Summer Readiness for Offsite and Alternate-ac Power

a. Inspection Scope

The inspectors performed a review of preparations for summer weather for selected systems, including conditions that could lead to loss-of-offsite power and conditions that could result from high temperatures. The inspectors reviewed the procedures affecting these areas and the communications protocols between the transmission system operator and the plant to verify that the appropriate information was being exchanged when issues arose that could affect the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the transmission system operator and the plant's operations personnel during off-normal or emergency events

- The explanations for the events

- The estimates of when the offsite power system would be returned to a normal state

- The notifications from the transmission system operator to the plant when the offsite power system was returned to normal

During the inspection, the inspectors focused on plant-specific design features and the procedures used by plant personnel to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. Specific documents reviewed during this inspection are listed in the attachment. The inspectors also reviewed corrective action program items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Alternate AC readiness and service water systems

These activities constitute completion of one readiness for summer weather affect on offsite and alternate-ac power sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

.2 Readiness to Cope with External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Updated Final Safety Analysis Report for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed an inspection of the protected area to identify any modification to the site that would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the abnormal operating procedure for mitigating the design basis flood to ensure it could be implemented as written. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one external flooding sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- April 14, 2010, Core spray A
- May 19, 2010, High pressure coolant injection
- May 26, 2010, 69kV and 12.5kV switchyard alignment

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Final Safety Analysis Report, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also inspected accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of 10 CFR 50 App B Criterion III, “Design Control,” in which the licensee failed to maintain accurate design drawings of the service water system discharge piping. Specifically, Drawing BR 2120, “Yard Circ. & Service Water Piping Plan & Sections,” Revision 14 incorrectly identified the as-left configuration of the service water system discharge piping, and was used as a design input to numerous essential calculations.

Description. During followup of degraded service water system performance from Refueling Outage 25 that occurred in October 2009, the licensee discovered that the configuration of the combined service water/circulating water common discharge lines was not as depicted on Drawing BR 2120, “Yard Circ. & Service Water Piping Plan & Sections,” Revision 14. Specifically, BR 2120 showed that the two divisional pipes terminated 24 feet apart, protruding from the west bank of the plant discharge canal a few feet below the waterline. In contrast, divers discovered that the pipes instead terminated at the bottom of the discharge canal only 6 inches apart.

Inspectors learned that the as-found piping configuration was meant by the Architect-engineer to be an interim step in the fabrication process. Drawing BR 2120 was developed during plant construction and was revised regularly as the service water system and circulating water system were constructed. The service water discharge piping first appears in the drawing in Revision 7, dated March 5, 1968. In this drawing, the as-found piping configuration was depicted (pipes terminated at the bottom of the canal, 6 inches apart). The architect-engineer then performed an options analysis of different piping configurations in an effort to reduce the impact of siltation on the service water piping, resulting in the recommendation that Nebraska Public Power District separate the pipes by 24 feet and move their termination point to high on the west bank of the discharge canal to avoid siltation and the likelihood of common mode failure. This recommendation was reflected in BR 2120 Revision 13, July 12, 1970. The change notes on the drawing indicated that the purpose of the revision was "changed termination point of 24" SW-2/CW-2 lines".

The licensee's decision regarding this option was documented in Burns and Roe Design Information Notice 2978-02, July 31, 1973, which states the following:

> "NPPD has approved the revised SW-2/CW-2 discharge piping into the circ water discharge canal generally as shown in study dwg 264. Please show the revised piping such that the 24" CW-2 discharges through the side of the canal rip rap at center line elevation 867', approximately 2 feet past the rip rap."

Based on this discussion, BR 2120 was updated in Revision 14 to label BR 2120 as a construction document versus a design sketch. A subsequent Burns and Roe memorandum dated August 2, 1973, however, documents the following:

> "The service water piping into the discharge canal has been modified to prevent silt blockage of the exit piping by rerouting piping through the side of the discharge canal at an elevation 7 feet above the bottom of the canal. This is being held in abeyance by NPPD."

The memo contained no discussion of why the design change was being held in abeyance. The licensee was unable to find any records to help understand the rationale for not implementing the design change. The net result is that BR 2120 reflected a planned, but never implemented, design change to the service water system discharge piping. No further changes were made for BR 2120 until after the discovery of the configuration error in October 2009.

Although the licensee identified that the discharge lines were not depicted on Drawing BR 2120, the inspectors added value by identifying that BR 2120 had been used as a design input into NEDC 92-034, "Water Hammer Analysis of Service Water System." NEDC 92-034 is a design basis calculation that was performed to document the response of the service water system to potential water hammer affects during design basis events. This calculation depended on an analytical model of the service water system that was developed based upon available drawings, one of which was BR 2120; however, BR 2120 contained substantial errors in that it documented the wrong elevation of the discharge point and did not include several ninety degree pipe bends that exist in the as-built piping. As a result, the calculation result was called into question by the inspectors.

In response to this question, the licensee initiated CR-CNS-2010-03689 and completed an operability evaluation that demonstrated that the service water system was operable despite this unanalyzed condition. Additional corrective actions have since been identified, including an action to re-perform the affected calculation. Additionally, an extent of condition review by the licensee identified five other calculations that appear to have used BR 2120 as a design input.

The inspectors determined that this represented a failure to document the plant design in applicable drawings. Reviews by the inspectors did not identify any recent opportunities to discover the error prior to October 2009.

Analysis. The inspectors determined that the finding is a performance deficiency in that the licensee failed to maintain accurate design drawings of the service water system discharge piping. The finding was more than minor because it affected the design control attribute of the mitigating systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was characterized under the significance determination process as having very low safety significance because all of the screening questions in the Manual Chapter 0609, Attachment 4, “Initial Screening and Characterization of Findings” Phase 1 screening table were answered in the negative. The inspectors determined that no cross cutting aspect was applicable to this finding due to the age of the performance deficiency and the lack of recent identification opportunities.

Enforcement. 10 CFR 50 Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that the design basis for structures, systems, and components that could prevent or mitigate the consequences of postulated accidents are correctly translated into drawings. Contrary to this requirement, from the beginning of power operations on January 18, 1974, to present, the plant drawings used to document the design of the service water discharge piping were incorrect. As a result, incorrect information was used as in input to numerous essential calculations and analyses. Because the finding is of very low safety significance and has been entered into the licensee’s corrective action program as CR-CNS-2010-03689, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2010003-01, "Failure to Document Design of Service Water Discharge Piping in Plant Drawings.”

.2 Complete Walkdown

a. Inspection Scope

On April 14, 2010, the inspectors performed a complete system alignment inspection of the Reactor Core Isolation Cooling system to verify the functional capability of the system. The inspectors selected this system because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors inspected the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. The inspectors reviewed a sample of past and outstanding work orders to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the corrective action program database to ensure that system equipment-alignment problems were being identified and appropriately resolved. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one complete system walkdown sample as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- April 7, 2010, Diesel generator 1B room, Zone 14B
- April 7, 2010, Diesel generator 1B diesel oil day tank room, Zone 14D
- April 14, 2010, Reactor building 859 feet 9 inch level, Zone 1B
- April 14, 2010, Hydraulic drive pump room, Zone 1G

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly fire-protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On April 13, 2010, and June 9, 2010, the inspectors observed a crew of licensed operators in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms
- Crew's correct use and implementation of abnormal and emergency procedures
- Control board manipulations
- Oversight and direction from supervisors
- Crew's ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew's performance in these areas to pre-established operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two quarterly licensed-operator requalification program samples as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- April 25, 2010, Barksdale pressure switch failures
- May 12, 2010, Extent of condition review of RHR-MOV functional failure evaluations
- May 13, 2010, Safety relief pilot valve test failures
- June 3, 2010, RHR-MO-15D valve failure to open functional failure evaluations

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b)
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring
- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or -(a)(2)
- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance

through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of 10 CFR 50.65(a)(2), requirements for monitoring the effectiveness of maintenance at nuclear power plants, for failure to demonstrate that the performance of the essential 4160 volt alternating current power system was effectively controlled through appropriate preventive maintenance. As a result, the licensee did not establish goals or monitor the performance of the essential power system Agastat relays per 10 CFR 50.65(a)(1) to ensure appropriate corrective actions were initiated when a revised evaluation of a Agastat time delay relay failure incorrectly changed the initial functional failure determination. Incorrectly changing this maintenance preventable functional failure resulted in the affected function, EE-PF03A, not reaching the licensee's maintenance rule (a)(1) threshold.

Description. The licensee had two functional failures associated with the 4160 volt essential power supply function EE-PF03A in 2008. EE-PF03A's function is to provide essential 4160 volt alternating current power to the Division 1 critical station electrical auxiliary loads. These two functional failures exceeded the threshold to perform a maintenance rule (a)(1) evaluation to determine if system performance was effectively controlled through appropriate maintenance.

The first functional failure occurred March 3, 2008, when an Agastat time delay relay failed repeated attempts to calibrate. This relay is required to open the Division 1 critical feeder breaker on low voltage prior to the low voltage condition damaging essential equipment such as the motors on emergency core cooling pumps. This was related to a long standing problem with Agastat time delay relays having foreign material introduced during manufacturing that introduced random changes in the timers countdown performance. The licensee had been handling this issue for several years by frequent preventative maintenance to monitor Agastat relays for normal wear and indications of foreign material degraded performance. Therefore, this was a maintenance preventable functional failure. Condition Report CR-CNS-2008-01352 was initiated to resolve this problem.

The second functional failure occurred October 28, 2008, when an essential service water pump supply breaker failed to close and start the pump when loose screws on the breakers micro switch prevented it from functioning. The loose screws were due to inadequate oversight of the breaker refurbishment process and therefore, a maintenance preventable functional failure. Condition Report CR-CNS-2008-07910 was initiated to resolve this problem.

A December 23, 2008, licensee's maintenance rule expert panel meeting determined that these two maintenance rule preventable failures required placing the function EE-PR03A in (a)(1) status to monitor the performance of the Division 1 essential 4160 volt alternating current supply against goals to ensure this system is capable of fulfilling its function. Several months passed while the licensee attempted to determine what would be the appropriate goals and corrective actions to address these functional failures.

On March 23, 2009, the maintenance rule expert panel returned the function EE-PF03A to (a)(2) status based on a revision of the March 3, 2008, Agastat relay functional failure evaluation. This revised evaluation determined that the Agastat relay failure was not a maintenance rule functional failure due to the failed relay timer results being less than the design function time requirement of 17 seconds by 0.3 seconds. The 17 seconds is the design basis time exposure below which essential motors are assumed to not be damaged by undervoltage conditions. Based on this revised functional failure evaluation conclusion, the relay was capable of providing adequate control for the associated essential equipment and was not a functional failure. This lowered the EE-PF03A function failures below the threshold that required meeting 10CFR50.65.(a)(1) requirements. However, the inspectors identified that this evaluation used an invalid assumption. It used data from the four failed attempts to calibrate an Agastat relay that was operating unpredictably and required replacement. The use of this data was determined to be unacceptable because it was obtained from a relay that was operating unpredictably and required subsequent replacement. As such, the inspectors determined that the revised functional failure was not valid. 10 CFR 50.65 (a)(2) requires that the function EE-PR03A performance be effectively controlled through the performance of appropriate preventative maintenance. The two functional failures demonstrate that the requirements of (a)(2) were not being met. Therefore, the incorrect assumption used in the revised fictional failure evaluation resulted in the Cooper Station being in violation of 10 CFR 50.65(a)(2).

A problem identification and resolution inspection team noted similar issues with other Agastat time delay relays during an inspection in March and April 2009. The results of the team's finding is documented in Inspection Report 05000298/2009007 as a noncited violation for the licensee's failure to perform adequate operability determinations of degraded and potentially degraded conditions associated with essential Agastat time delay relays with internal foreign material contamination. One of the licensee's corrective actions was to implement a design change to replace 22 time critical Agastat relays with digital time relays. The relay associated with the March 3, 2008, functional failure was replaced with the digital upgrade in October 2009. The effectiveness of this corrective action is monitored by the licensee's corrective action program.

Following the guidance of Appendix B to MC 0612 this finding is more than minor because failure to monitor the effectiveness of the Division 1 essential 4160 volt alternating current supply system affects the reliability objective of the Equipment Performance attribute under the Mitigating Systems Cornerstone. This issue was screened with the assistance of Inspection Procedure 71111.12, “Maintenance Effectiveness,” Appendix D, “Regulatory Review,” that supplements the general guidance of IMCs 0612 and 0609 by providing specific guidance on the disposition of maintenance effectiveness issues. This is a Category II maintenance effectiveness issue in that this failure to establish goals and monitoring for the essential 4160 volt alternating current supply system is not attributable to poor Agastat relay performance but a result of an inadequate licensee functional failure evaluation. Since the equipment reliability problems were corrected by the licensee’s corrective action program via a design change and the maintenance rule violation has occurred as a separate consequence of the Agastat relay problems, this cannot be processed through the significance determination process.

Analysis. The inspectors determined that the failure by licensee personnel to correctly determine that the maintenance rule (a)(1) threshold had been reached was a performance deficiency. This finding is more than minor because failure to monitor the effectiveness of the essential 4160 volt alternating current function, EE-PF03A, affects the reliability objective of the Equipment Performance attribute under the Mitigating Systems Cornerstone. The inspectors determined that this performance deficiency was an additional, but separate consequence of the degraded performance of the essential 4160 volt alternating current system Agastat relays. Following the guidance of Appendix B to MC0612 and Appendix D to IP 71111.12, the inspectors determined that this finding occurred as a consequence of actual problems with the Agastat relays, and that those actual problems were not attributable to this finding. This finding therefore cannot be processed through the significance determination process, and is considered to be Green by NRC staff review. The finding has a crosscutting aspect in the area of human performance associated with decision-making because the licensee did not use conservative assumptions in the functional failure evaluation of a Agastat relay failure [H.1(b)].

Enforcement. Title 10 CFR 50.65(a)(1) requires, in part, that holders of an operating license shall monitor the performance or condition of structures, systems and components within the scope of the rule as defined by 10 CFR 50.65(b), against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended safety functions. 10 CFR 50.65(a)(2) states, in part, that monitoring as specified in 10 CFR 50.65(a)(1) is not required where it has been demonstrated that the performance or condition of an system is being effectively controlled through the performance of appropriate preventive maintenance, such that the system remains capable of performing its intended function. Contrary to this requirement, from December 28, 2008, to the present, the licensee did not demonstrate that the performance of the 4160 volt alternating current system had been effectively controlled through appropriate preventative maintenance and did not monitor against licensee-established goals in a manner sufficient to provide reasonable assurance that the essential electrical supply system was capable of fulfilling its intended safety functions. Specifically, the licensee failed to identify and properly account for maintenance preventable functional failures that occurred March 3, 2008 and October 28, 2008, that demonstrated that the performance of the Division 1 essential 4160 volt alternating current system was not being effectively controlled through the performance of appropriate preventative maintenance and, as a result, that goal setting and monitoring was required. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as CR-CNS-2010-5587, this violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000298/2010003-02, "Failure to Place the essential 4160 volt alternating current system Agastat relays in (a)(1)."

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- April 6, 2010, Diesel generator 1 work window
- May 11, 2010, High pressure coolant injection filter inspection
- June 3, 2010, Diesel generator 2 walkdown without Control Room notification during Yellow window with diesel generator 1 I lockout
- June 8-9, 2010, Reactor recirculation motor generator pump B maintenance and return to service

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four maintenance risk assessments and emergent work control inspection samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- April 9, 2010, Service water discharge piping
- April 21, 2010, RHR-MO-15D failure
- May 20, 2010, Service water booster pump D water in oil
- May 20, 2010, RHR-A motor heater wiring discolored

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and UFSAR to the licensee personnel's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four operability evaluations inspection sample(s) as defined in Inspection Procedure 71111.15-04

b. Findings

No findings were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- May 5, 2010, Service water pump C impeller lift
- May 7, 2010, Diesel generator fuel oil modification testing

- May 11, 2010, High pressure coolant injection filter inspection
- May 13, 2010, Reactor building crane postmaintenance test
- May 20, 2010, “H” intermediate range monitor post maintenance testing
- May 21, 2010, Ronan power supply replacement post maintenance testing

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed

- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the Updated Final Safety Analysis Report, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of six postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, procedure requirements, and technical specifications to ensure that the surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning

- Evaluation of testing impact on the plant

- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data
- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- April 21, 2010, Residual heat removal pump D, motor operator 15D failure
- May 12, 2010, Diesel generator fuel oil special test
- May 25, 2010, Performance of offsite AC power alignment to support 6.1DG.301
- May 26, 2010, Reactor coolant system leak rate checks

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. <u>Findings</u>

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures (MS05)

a. Inspection Scope

The inspectors sampled licensee submittals for the safety system functional failures performance indicator for the period from the second quarter 2009 through the first quarter. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73." The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports, and NRC integrated inspection reports for the period of April 2009 through March 2010, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one safety system functional failure sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.2 Reactor Coolant System Specific Activity (BI01)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity performance indicator for the period from the second quarter 2009 through the second quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's reactor coolant system chemistry samples, technical specification requirements, issue reports, event reports, and NRC integrated inspection reports for the period of March 2009 through May 2010, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one reactor coolant system specific activity samples defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.3 Reactor Coolant System Leakage (BI02)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for the period from the second quarter 2009 through the second quarter 2010   To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6. The inspectors reviewed the licensee’s operator logs, reactor coolant system leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of March 2009 through May 2010, to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one reactor coolant system leakage sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee’s corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors focused their review on repetitive equipment issues, but also considered the results of daily corrective action item screening discussed in Section 4OA2.2, above, licensee trending efforts, and licensee human performance results. The inspectors nominally considered the 6-month period of

October 2009 through March 2010 although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors also included issues documented outside the normal corrective action program in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's corrective action program trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

These activities constitute completion of one single semi-annual trend inspection samples as defined in Inspection Procedure 71152-05.

b. Findings and Observations

No findings were identified. The inspectors evaluated the licensee's trending methodology and observed that the licensee had performed a detailed review. The licensee routinely review cause codes, involved organizations, key words, and system links to identify potential trends in their corrective action program data. The inspectors compared the licensee process results with the results of the inspectors' daily screening and did not identify any discrepancies or potential trends in the corrective action program data that the licensee had failed to identify. The inspectors did, however, identify additional insights into several of these issues as documented below:

Human Error Prevention Techniques Substantive Cross-Cutting Issue Review.

The NRC identified a crosscutting theme associated with the work practices component of the human performance area related to the use of human error prevention techniques [H.4(a)] in 2008. Since the licensee recognized the theme and developed corrective actions, a crosscutting issue was not identified for the 2008 human performance issue.

During the 2009 assessment period seven findings were identified with the crosscutting aspect related to the use of human error prevention techniques. Five of these occurred following full implementation of the licensee's corrective actions. Based on these findings with the repeated common theme, the NRC staff identified a substantive crosscutting issue in the human performance area associated with work practices related to the use of human error prevention techniques at Cooper Nuclear Station [H.4(a)]. These findings occurred in initiating events, barrier integrity and occupational radiation safety cornerstones. This baseline inspection semi annual trend continues to monitor for sustainable performance improvements as evidenced by effective implementation of an appropriate corrective action plan that results in no safety significant inspection findings and a notable reduction in the overall number of inspection findings with the same common theme.

A comparison of the licensee's human performance trends from their condition report record in 2009 versus the trends from early 2010 was performed. Consequential human errors and non-consequential human errors were higher in 2009 than 2010. The majority of 2009 errors were during the fall 2009 refueling outage, as expected, due to the large number of activities performed during an outage versus normal plant operation. The same effect was noted for procedure quality and adherence issues with an increasing trend during the fourth quarter 2009 compared to a decreasing trend during the first quarter 2010.

The licensee improvement plan while mainly implemented has a few actions that are completing during June and July 2010. This is a non-refueling year for the licensee. The gross number of maintenance activities is substantially lower and so the opportunities for human performance errors are correspondingly lower. Based on the lower number of activities performed during full power operations compared to a refueling outage and the need to allow time to observe the effectiveness of the licensee improvement plan the NRC will continue to monitor the licensee's progress via the baseline inspection program.

Trend in Inadequate Apparent Cause Reviews:

During routine corrective action program document reviews, the inspectors noted that the apparent cause evaluation performed under CR-CNS-2010-02875 had been flagged as inadequate during the licensee's effectiveness review. The inspectors noted that Corrective Action Program Desk Guide #7, "Just in Time (JIT) Training for Apparent Causes," Revision 0, requires apparent cause evaluators to receive just-in-time training prior to performing this activity. In the case of CR-CNS-2010-02875 the inspectors noted that the apparent cause evaluator had been exempted from the licensee's normal just-in-time training. As a result, the inspectors reviewed the results of apparent cause effectiveness evaluations for the previous year and discovered that eleven apparent cause evaluations had been flagged as inadequate. Four of these were performed by persons who were exempted from the required just-in-time training. Another five inadequate evaluations were performed by persons who received the training via a video tape versus in person. Lastly, the inspectors noted that one individual had been flagged for an inadequate evaluation on three separate occasions in the past year but had received the "initial" just in time training prior to performing each of the inadequate evaluations. The inspectors also noted that the licensee had made no attempt to evaluate this adverse trend or take any corrective actions to improve performance. The inspectors determined that the record of inadequate apparent cause evaluations reveals several potential gaps in the administration of the just-in-time training required by Desk Guide #7.

Trend in Back Leakage into F Sump:

The inspectors reviewed the collection of drywell unidentified leak rate data for adverse trends. The licensee's "F" sump collects unidentified leakage in the drywell, and a pair of pumps remove the water by pumping it to the liquid radwaste system. A flow totalizer measures the total volume of water pumped every eight hours, and from this a measured unidentified leak rate is determined to satisfy technical specification surveillance requirements. The discharge lines from each pump contain a check valve to prevent back leakage into the sump from the liquid radwaste system. These check valves have been historically poor at preventing back leakage. On at least four occasions in previous twelve months, operators questioned the accuracy of the

measured leak rate and isolated the pump discharge lines in order to determine a meaningful leak rate.
The back leakage problem has routinely caused the measured leak rate to be off by over 0.1 gpm.

The inspectors reviewed Regulatory Guide 1.45, “Reactor Coolant Pressure Boundary Leakage Detection Systems,” May 1973, which establishes sensitivity requirements for leak rate sensing systems of Cooper’s vintage. Even with the worst case back leakage seen to date, the licensee still satisfied the required instrument sensitivity of detecting a one gpm leak rate in less than one hour. The back leakage problem, however, has caused unnecessary entries into Procedure 0-CNS-OP-109, “Drywell Leakage Investigation,” to look for leakage that did not exist. Procedural 0-CNS-OP-109 requires operators to begin looking for leak sources when measured leakage exceeds 0.25 gpm. The back leakage issue has caused operators to question the measured leak rate and become accustomed to routinely entering Procedure 0-CNS-OP-109. This effectively desensitizes control room operators to small changes in drywell unidentified leak rate and could interfere with prompt identification of developing reactor coolant system leakage.

The licensee has a standing maintenance task to replace the leaking check valves each outage, but this strategy has not been successful in eliminating the back leakage issue. The licensee has planned a modification to be implemented in Refueling Outage 26, which will replace the existing valves with a soft-seated design. The inspectors noted that this modification was also planned for Refueling Outage 25, but was deferred due to having minimal beneficial value as described in the response to CR-CNS-2009-00003.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report 05000298/2010-001-00, Safety Relief Valves Test Exceeded Technical Specification Limits

a. Inspection Scope

On January 12, 2010, two safety relief valve pilot assemblies as-found pressure setpoints exceeded the technical specification SR 3.4.3.1 limits when tested in a test shop. Three safety relief valves and five safety relief valves pilot assemblies were removed during the licensee’s fall 2009 refueling outage. The replacement pilot assemblies installed during the fall 2009 refueling outage were refurbished and certified to lift within the setpoint acceptance criteria prior to installation. The licensee investigation determined the failures were due to pilot disc-to-seat corrosion bonding. A corrective action that has not been fully implemented was developed from previous failures described in LER 2008-002-00. This action is to submit a technical specification license amendment to allow one or two failures out of the eight total safety relief valves without exceeding technical specification limits. No new findings were identified in the inspector’s review. This finding constitutes a minor violation of Technical Specification Surveillance Requirement 3.4.3.1. that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This Licensee Event Report is closed.

b. Findings

No findings were identified.

.2 Work Preparation Activities Cause Unplanned Increase in Reactor Power

a. Inspection Scope

On April 28, 2010, a work planner affected a leaking feedwater heater control valve during a planning walkdown. The reactivity increase due to the change in feedwater temperature caused the reactor to exceed the licensed thermal power limit of 2419 MWt until reactor operators reduced power. The event was reviewed by the inspectors and a green noncited violation was identified for the licensee's failure prevent the operation of plant equipment of which may affect the reactivity or power level of a reactor without the knowledge and consent of a licensed operator or senior operator present at the controls. This finding is described below.

b. Findings

Introduction. A Green self-revealing noncited violation of 10 CFR 50.54.j was identified when a work planner caused a feedwater heater trip by touching a pressure regulating valve without the knowledge of the control room. The reactivity increase due to the change in feedwater temperature caused the reactor to exceed the licensed thermal power limit of 2419 MWt until reactor operators reduced power.

Description. On April 28, 2010, a work planner was preparing a work package for repair of an air leak on CNS-0-CD-PRV-PRV10, the pressure regulating valve for the A5 feedwater heater level control valve. While walking down the area of the repair, the planner observed that the leak was larger than expected. The planner then applied pressure with his hands around the gasket in the vicinity of the leak. He did not report or request permission for this action from the control room. When he covered the leak with his hands, the change in leak rate resulted in a transient of the level control valve signal.

The signal transient caused the level in the A5 heater to drop by dumping condensate to the A3 heater. The A3 feedwater heater has been operated with the level control valve in manual since November 30, 2009, due to excessive cycling of the associated level control valve; therefore, the A3 heater did not automatically respond to the rapid increase in level. The control room received both the A5 HEATER LOW LEVEL and A3 HEATER HIGH LEVEL alarm at 8:24 a.m. The A3 HEATER HIGH LEVEL TRIP alarm came in 1 minute later. Over the next 30 minutes, the operators attempted to stabilize feedwater heater levels. The feedwater heater trip and level transients resulted in an approximately 0.8°F drop in feedwater temperature, which caused an increase in reactor power to 2421 MWt. The operators immediately reduced power with recirculation pumps to 2419 MWt.

In response to the event, the licensee performed an apparent cause evaluation and a human performance evaluation. The human performance evaluation indicated that a "two-minute drill" had not been performed. In the apparent cause evaluation, the licensee stated the planner had exceeded the scope of job by touching the component instead of visually inspecting it. The licensee also stated in the evaluation that "interviews with valve team personnel revealed that they had cautioned a non-licensed operator the previous day about not touching the pressure relief valve due to the potential to affect the air control signal." The licensee's corrective actions included coaching the work planner, training plant personnel on the potential for causing a plant transient during system walkdowns, and establishing pre-job briefs for the planning department. In addition, caution tape was placed around the pressure regulating valve.

Analysis. The licensee failing to ensure that mechanisms which may affect reactivity were manipulated only with the knowledge and consent of a licensed operator at the controls was a performance deficiency. The finding was more than minor because the performance deficiency could be reasonably viewed as a precursor to a significant event in that a reactor power transient was initiated without the knowledge of the control room. Using Manual Chapter 0609.04 this finding was characterized under the significance determination process as having very low safety significance because while the finding degraded the transient initiator contributor function of the initiating events cornerstone, it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The inspectors determined that this finding has a crosscutting aspect in the area of human performance associated with the work practices component because the work planner proceeded in the face of unexpected circumstances by exceeding the scope of the job when he found the leak was greater than expected [H.4(a)].

Enforcement. 10 CFR 50.54.j requires, in part, that apparatus and mechanisms other than controls, the operation of which may affect the reactivity or power level of a reactor, shall be manipulated only with the knowledge and consent of a licensed operator or senior operator present at the controls. Contrary to the above, on April 28, 2010, a work planner manipulated the instrument air system, without the knowledge and consent of a licensed operator or senior operator present at the controls, causing a feedwater transient and reactivity change. However, because this inspection finding was characterized by the significance determination process as having very low risk significance (Green) and has been entered in the licensee's corrective action program as CR CNS-2010-03091, this violation is being treated as a noncited violation, consistent with Section IV.A.1 of the NRC Enforcement Policy: NCV 05000298/2010003-03, "Work Preparation Activities Cause Unplanned Increase in Reactor Power."

4OA5 Other Activities

Failure to Perform Required Maintenance Causes Unplanned Down Power

a. Inspection Scope

On May 1, 2010, control room operators initiated a rapid power reduction after receiving trip alarms on the A1 and A2 traveling water screens and subsequent loss of vacuum on the main condenser. After stabilizing power below the capacity of two circulating water pumps, operators tripped the A circulating water pump. The licensee's investigation determined that the cause of the traveling water screen trip was accumulated debris in the screen debris trough as a result of failing to perform the required routine maintenance on the traveling water screens.

b. Findings

Introduction. A Green self-revealing finding was identified for the licensee's failure to implement the preventive maintenance requirements of the vendor manual for the plant traveling water screens. Specifically, Vendor Manual 140, "Traveling Water Screen," Revision 35, contained daily and weekly routine maintenance requirements to open the channel-flushing valve to clear any accumulated debris from the screens. Despite the fact that the licensee incorporated this vendor manual into their preventive maintenance system, this maintenance requirement was overlooked. The failure to perform this maintenance task led to the trip of the A1 and A2 traveling water screens on May 1, 2010, and required an emergent power reduction.

Description. On May 1, 2010, the Missouri River was in the midst of a level transient, during which a large amount of debris was entering the intake structure and was being removed by the traveling water screens. At the time of the event, only three of the plant's four circulating water pumps were available due to maintenance activities affecting the fourth pump. Each circulating water pump can draw its required flow from one of two traveling water screens (there are two dedicated screens per pump).

The event began when control room operators received alarms suggesting that the A1 traveling water screen had tripped, followed shortly by similar alarms for the A2 screen. Operators made a failed attempt to restart the tripped screens but were unsuccessful. Operators entered Abnormal Operating Procedure 2.4VAC and recognized degrading vacuum on the main condenser. As a result, operators began a rapid power reduction to avoid a low-vacuum turbine trip. After reducing power to approximately seventy percent (within the capacity of two circulating water pumps), operators tripped the A circulating water pump from the control room.

Operators immediately inspected the A1 and A2 screens, and found an accumulation of river debris inside the debris flushing trough. The debris created drag on the screen baskets. This increased drag had caused the A1 screen to trip. When the full flow of the A circulating water pump was then diverted to the A2 screen, the high debris loading on the screens caused a high differential pressure trip of the A2 screen. After clearing the debris from the A1 screen, operators were again able to restore a two-screen lineup for the A circulating water pump, start the pump, and return the plant to full power.

In the root cause investigation performed under CR-CNS-2010-03195, the evaluators identified that the applicable vendor manual had identified a list of routine maintenance tasks. The evaluators identified the following daily maintenance task that was never incorporated into the licensee's preventive maintenance program or system operating procedures:

> "Check that debris is being washed off the screen into the debris channel and that the channel is clear. Briefly open the channel-flushing valve if necessary."

Additionally, the following weekly task was also omitted:

> “Open the flushing valves on the wash water jet pipes for approximately fifteen (15) seconds to clear any accumulated debris.”

The inspectors reviewed Change Evaluation Document 6014001, “Traveling Water Screens Replacement,” April 19, 2005, and learned that the modification package incorporated most of the maintenance tasks from the vendor manual, but was silent on operation of the channel-flushing valve. Interviews with licensee personnel suggested that this may have been due to a misunderstanding of the normal system lineup, or just an oversight on the part of the evaluator. Regardless of the cause, the net effect was that the design process never identified the need to routinely open the channel-flushing valve and led directly to the screen failure on May 1, 2010.

The inspectors determined that the age of the performance deficiency and lack of recent opportunities to discover this error suggested that this performance deficiency is not indicative of current performance.

In response to this event, the licensee performed a review of the applicable vendor manual preventive maintenance and instituted a nightly task to inspect the debris channel and cycle the channel flushing valves for each traveling water screen. The licensee also initiated actions to perform an extent of cause check of other important equipment that had been recently installed to ensure appropriate vendor recommended maintenance requirements have been implemented.

Analysis. The licensee’s failure to implement the required routine maintenance for the traveling water screens is a performance deficiency. The finding was more than minor because it affected the equipment performance attribute of the initiating events cornerstone, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using Manual Chapter 0609.04 this finding was characterized under the significance determination process as having very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation functions would be unavailable. The inspectors determined that no crosscutting aspect was applicable to this finding because the performance deficiency was not reflective of current performance.

Enforcement. Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as FIN 05000298/2010003-04, "Failure to Perform Required Maintenance Causes Unplanned Down Power.”

4OA6 Meetings

Exit Meeting Summary

On July 1, 2010, the inspectors presented the inspection results to Mr. Brian O'Grady, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On July 12, 2010, the inspectors conducted a telephonic exit meeting to present changes in the inspection results to Mr. Dave VanDerKamp. The licensee acknowledged the changes to the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee Personnel

A. Able, Instrument & Control Engineering Supervisor, Design Engineering Department
D. Anderson, Supervior, ALARA
J. Austin, Manager, Emergency Preparedness
D. Buman, Director of Engineering
B. Chapin, Manager, Outage
S. Charbonnet, NPPD ESD Lead
R. Dewhirst, Senior Project Manager
R. Estrada, Manager, Design Engineering
K. Fike, Plant Chemist, Chemistry Department
J. Flaherty, Licensing
S. Freborg, ESD Mechanical Programs Supervisor
G. Gardner, NSSS Supervisor, System Engineering Department
K. Gehring-Ohrablo, Chem Tech, Chemistry Department
T. Hough, Maintenance Rule Coordinator
N. Joergensen, Design Engineer
L. Keiser, SW and RHR System Engineer
D. Kirkpatrick, Technician, Radiation Protection
P. Leininger, Erosion/Corrosion Program Engineer
D. McMahon, REC System Engineer
A. Meinke, Chemistry Engineer, Chemistry Department
M. Metzger, System Engineer
D. Madsen, Licensing
D. Parker, Manager, Maintenance
R. Penfield, Manager, Operations
A. Sarver, BOP/Elect/I&C Supervisor, System Engineering Department
K. Tanner, Supervisor, Radiation Protection
J. Teten, Chemistry Supervisor
D. VanDerKamp, Licensing Manager
J. Webster, Director of Projects, Project Department
R. Wulf, SED Manager
A. Zaremba, Director Nuclear Safety Assurance

NRC Personnel

Runyan, Mike, Senior Risk Analyst

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2010003-01	NCV	Failure to Document Design of Service Water Discharge Piping in Plant Drawings
05000298/2010003-02	NCV	Failure to Place the Essential 4160 Volt Alternating Current System Agastat Relays in (a)(1)
05000298/2010003-03	NCV	Work Preparation Activities Cause Unplanned Increase in Reactor Power
05000298/2010003-04	FIN	Failure to Perform Required Maintenance Causes Unplanned Down Power

LIST OF DOCUMENTS REVIEWED

Section 1RO1: Adverse Weather Protection

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	DATE
EE-SY	CNS System Health Report	March 2010

Section 1RO1: Adverse Weather Protection

PROCEDURE

NUMBER	TITLE	REVISION
2.1.14	General Operating Procedure, “Seasonal Weather Preparations”	14
5.1FLOOD	Emergency Procedure, “Flood”	7
5.3GRID	Emergency Procedure, “Degraded Grid Voltage”	29
7.0.11	Maintenance Procedure, “Flood Control Barriers”	9

WORK ORDER

4663687

Section 1RO4: Equipment Alignment

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION / DATE
	Burns and Roe Design Information Notice, "Service Water System Modification Circ. Water Discharge Canal Piping"	7/31/73
	Core Spray Component Checklist	2
CNS-RCIC-1	"Flow Diagram RCIC Turbine Lube Oil Subsystem"	3/10/89
NEDC 92-034	"Water Hammer Analysis of Service Water System"	3C1
2043	Burns & Roe, "Flow Diagram Reactor Core Isolation Coolant and Reactor Feed Systems Cooper Nuclear Station"	NS4
2044	Burns & Row, Cooper Nuclear Station Flow Diagram – High Pressure Coolant Injection and Reactor Feed System	N70
2045	SH1 Core Spray System	N58
95516C	"EG-R Governor Hydraulic System General Electric RCIC Units"	2/08/74

Section 1RO4: Equipment Alignment

PROCEDURE

NUMBER	TITLE	REVISION
2.2.33A	System Operating Procedure, "High Pressure Coolant Injection System Component Checklist"	24
2.2.67A	CNS Operations Manual System Operating Procedure, "Reactor Core Isolation Cooling System Component Checklist"	20
3.7	Engineering Procedure, "Drawing Change Notice"	31
3.8	Engineering Procedure, "Drawing Control"	22
6.EE.610	Surveillance Procedure, "Off-Site AC Power Alignment"	24

CONDITION REPORT

CR-CNS-2009-02859 CR-CNS-2009-03689

Section 1RO5: Fire Protection

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	DATE
	FHA FA Drawing, FHA Matrix FA1-FZ1B	2/28/03
	FHA FA Drawing, FHA Matrix FA1-FZ1G	2/28/03
93-15	Engineering Evaluation	
NFPA 30	“Flammable and Combustibles Liquids Code”	1973 Edition

Section 1R11: Licensed Operator Requalification Program

LESSON

NUMBER	TITLE	REVISION
SKL0540132		0

Section 1R11: Licensed Operator Requalification Program

SCENARIO OVERVIEW

Aircraft Threat, Vehicle Accident Breaches Secondary Containment, Spurious Group 1 Isolation, Failure to Scram, Fuel Clad Failure

Section 1R12: Maintenance Effectiveness

NOTIFICATION

NUMBER	TITLE
10711374	
10727134	Component RHR-MO-MO15D, RHR Pump Shutdown Cooling Suction Motor Operated Valve Functional Failure Evaluations for Functions: RHR-PF01B, RHR-PR02B, RHR-PF03B, RHR-PF04B and RHR-SD1

CONDITION REPORT

CR-CNS-2010-02334 CR-CNS-2010-02355 CR-CNS-2010-02709

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

PROCEDURE

NUMBER	TITLE	REVISION
0.40.9	Administrative Procedure "Work Activity Risk Management Process"	2
0.49	Administrative Procedure	

CONDITION REPORT

CR-CNS-2010-04001

WORK ORDER

4731476 473857

Section 1R15: Operability Evaluations

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION / DATE
	Nebraska Public Power District Letter, "Response to Generic Letter 89-13"	January 29, 1990
EN-OP-104	Operability Determinations	3

Section 1R15: Operability Evaluations

PROCEDURE

NUMBER	TITLE	REVISION
0.5.OPS	Administrative Procedure, "Operations Review of Condition Reports/Operability Determination"	29
2.0.11	Conduct of Operations Procedure, "Entering and Exiting Technical Specification/TRM/ODAM LCO Condition(s)"	27
2.0.11.1	Conduct of Operations Procedure, "Safety Function Determination Program"	4

CONDITION REPORT

CR-CNS-2006-00471 CR-CNS-2009-08848 CR-CNS-2010-02347 CR-CNS-2010-02529
CR-CNS-2010-02709 CR-CNS-2010-03592 CR-CNS-2010-03641

WORK ORDER

4740871

Section 1R19: Postmaintenance Testing

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	REVISION
6.2 IRM.304	IRM Channel Calibration (Mode Switch in Run)(Div 2)	21
NEDC 91-045	Diesel Fuel Transfer Flow Rate with 8 3/8 Pump Impeller	1C1

Section 1R19: Postmaintenance Testing

PROCEDURE

NUMBER	TITLE	REVISION
3.4.7	Engineering Procedure, "Design Calculations"	31
6.1DG.401	Surveillance Procedure, "Diesel Generator Fuel Oil Transfer Pump IST Flow Test (Div 1)"	27
6.1SW.101	Surveillance Procedure, Service Water Surveilllance Operation (Div 1)(IST)	31

WORK ORDER

4625372	4656444	4664046	4731476	473857

Section 1R22: Surveillance Testing

PROCEDURE

NUMBER	TITLE	REVISION
6.EE.610	Surveillance Procedure, "Off-Site AC Power Alignment"	24
6.LOG.601	Surveillance Procedure, "Daily Surveillance Log – Modes 1, 2, and 3," Attachment 3 Unidentified Leak Rate and Attachment 4 Identified and Total Leak Rate Checks	103
6.1DG.401	Surveillance Procedure, "Diesel Generator Fuel Oil Transfer Pump IST Flow Test (Div 1)"	27
6.2RHR.201	Surveillance Procedure, "FHR Power Operated Valve Operability test (IST)(Div 2)"	21

CONDITION REPORT

CR-CNS-2010-2709

WORK ORDER

4705353 4705582

Section 4OA1: Performance Indicator Verification

MISCELLANEOUS DOCUMENTS

NUMBER	TITLE	DATE
8.4.1.1B	Chemistry Report, Gamma Detector Nuclide Identification Sheet for Reactor Iodine	5/20/10
	Chemistry Department “Dailies and Weeklies Hints Table”	11/21/06
	Chemistry Measurements Database (Open CDM) Sample Pint RX WATER 8.4.1.1.1/8.4.1.1.2/8.4.1.1.3 Dose Equivalent Iodine 131	1/4/10-5/24/10
	Pre-Job Brief worksheet for Reactor Water Sampling	

Section 4OA1: Performance Indicator Verification

PROCEDURE

NUMBER	TITLE	REVISION
6.LOG.601	Surveillance Procedure, “Daily Surveillance Log – Modes 1, 2, and 3” – Attachment 3 Unidentified Leak Rate Checks and Attachment 4 Identified and Total Leak Rate Checks	103
8.4	Chemistry Procedure, “Routine Sampling and Sample Valve Control”	30
8.8DWAM	Chemistry Procedure, “Particulate and Iodine Sample Collection for Drywell Atmosphere Monitor”	2
8.8.1.14	Chemistry Procedure, “Radiochemical Iodines Analysis”	16

Section 4OA2: Identification and Resolution of Problems

MISCELLANEOUS DOCUMENTS

TITLE
Primary Control Rod System Reports

Section 4OA2: Identification and Resolution of Problems

PROCEDURE

NUMBER	TITLE	REVISION
6.1SW.101	Surveillance Procedure, “Service Water Surveillance Operation (Div 1)(IST)”	31

CONDITION REPORT

CR-CNS-2010-02745	CR-CNS-2010-02875	CR-CNS-2010-02932	CR-CNS-2010-02935